California:
The Real Story

A Situation Analysis by the Electric Power Supply Association

September 11, 2000

In recent weeks, much has been said about what happened to electricity prices in California this summer and why. We urge customers, market participants, regulators, legislators, analysts and commentators to look at all of the facts before rushing to conclusions or judgments about what happened. No one is well served by a rush to judgment or by perpetuating the unfounded allegations that have been swirling in California. In truth, what transpired was what was predicted by many in the market prior to the summer of 2000.

The solution lies in completing the transition to real competition as soon as possible. Implementing temporary "fixes" that continue to create uncertainty and distortions into the future, only prolonging the state's power-supply dilemma. To this end, the Electric Power Supply Association (EPSA) offers the following:

1. Supply and Demand

As in any commodity market, prices go up when demand outstrips supply. California is facing rising electricity demand accompanied by a severe shortage of generating capacity and supply availability:

- From 1996 to 1999, peak demand increased by 5,522 megawatts, while only 672 megawatts of net capacity was added.[1]
- Electricity demand in California has increased dramatically -- approximately 2% each year since 1990, or an average increase in demand of 1,000 megawatts a year.[2]
- California accounts for less than half of the demand in the Western Systems Coordinating Council (WSCC), which is also seeing significant load growth.[3]
- This year's average hydro conditions are running at about 88.5% of normal, compared with 112% in 1999.[4]
- Unusually hot weather blanketed much of the West this summer, with high temperatures seen simultaneously from Seattle to Phoenix on some days, particularly when compared with last summer, which was cooler than usual.[5]
- Fires in the West have knocked out some transmission lines, further limiting the movement of power and exacerbating the transmission constraints generally in California.

Generators faced new and different operational challenges this year.

- Natural gas prices this year roughly doubled from 1999, adding $25-$35 per megawatt hour to the cost of gas-fired generation.[6]

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[1] California Energy Commission (CEC)
[2] *California Energy Demand, 2000-2010,* CEC
[3] 2000 WSCC Information Summary
[4] *Megawatt Daily*, September 8, 1999 and September 8, 2000
[5] National Oceanographic and Atmospheric Administration

- The cost of emission credits has risen from $2.50 to $4 per pound in 1999 to $40 -$50 per pound this summer in the Los Angeles Basin, and fewer credits are available at any price. The combined cost of fuel and nitrogen oxide (NOx) credits for a natural gas-fueled peaking unit in the Los Angeles Basin is now approximately $147 per megawatt hour.[7]
- 61% of the California generating fleet is more than 30 years old, leading to a greater risk of forced outages and require more maintenance than newer plants. In addition, these older facilities have the potential for lower availability factors.[8]

2. New Investment: Getting It Done

As of September 2000, more than 14,000 megawatts of new capacity have been announced in California. Only four power plants were under construction, with only two scheduled to be on-line by the fall of 2000. Throughout the WSCC, only 915 megawatts were planned for the summer now ending, despite an estimated region-wide load growth of 3,600 megawatts. By the summer of 2001, 4,150 new megawatts will be on-line in the WSCC, with only 1,000 of those megawatts located in California.

Clearly, price caps and regulatory impediments to siting stifle investment. While some generation can successfully be built and operated under the caps, much-needed peaking units face a tougher situation. Units that operate only a few hours a year have to recover all of their fixed and operating costs over those limited hours of operation. From April 1999 to March 2000, generators supplying the last 10% of the California ISO's (Cal ISO) peak demand ran less than 33 hours. To recover just fixed and variable costs, with no earnings, the price would need to be over $1,450 per megawatt hour.[9] Of course, these generation owners assume the risk that these peaking units will run during these 33 hours, which may not be the case if sufficient new generation is built.

Price caps have other disruptive impacts in the market. In addition to dampening price signals for much needed investments, price caps also discourage demand-side response to higher prices, eliminating incentives customers might have to reduce load or switch suppliers to find a better deal. Price caps also introduce a measure of regulatory and political risk. This summer, price caps in California plummeted from $750 to $500 to $250 per megawatt hour, with calls for $100 per megawatt hour. This approach sends signals to national energy infrastructure companies, and the lenders who finance their power plant projects, that investing outside California makes better business sense in terms of capital deployment, risk management and return on investment.

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[6] *Natural Gas Intelligence*
[7] *Power Markets Week*, August 21, 2000. Recently, gas prices in California have reached $7.00/MMBtu. With a heat rate of 11,000 Btus per kilowatt hour, fuel costs per megawatt hour are $77. (At more typical fuel prices of $4 to $5 per MMBtu, the fuel price for gas generation is $44 to $55 per megawatt hour.) At $50 per pound for NOx emission credits, the average gas plant, which emits 1.4 pounds of NOx per megawatt hour, spends $70 for NOx credits to generate one megawatt hour.
[8] 1999 & 2000 WSCC Information Summaries
[9] Cal ISO Market Operations Report, Actual Loads from April 1999- March 2000

Price caps reflect another problem: they are completely arbitrary and do not reflect either the sellers' cost or customers' value of electric power.[10] Californians have been given an unrealistic expectation of what constitutes reasonable power prices during periods of scarcity. Indeed, under the old regulatory paradigm, utility prices were averaged, making actual costs less conspicuous.

The price of retail power for residential and small commercial customers has been capped for several years at a rate that reflected a 10% discount. Thus, customers in 2000 are expecting prices more compatible with pre-1996 prices. As noted above, natural gas prices and the cost of emissions credits, as well as the cost of basic power generation equipment, have risen significantly over that period. To base current and future price expectations on past circumstances misrepresents reality. To whatever extent policymakers insist on price caps, they should reflect tangible, reality-based metrics, not outdated assumptions.

In addition to price caps, the regulatory environment in California makes building power plants an unnecessarily difficult undertaking. Numerous regulatory agencies are involved, imposing time delays and stringent permitting requirements, often with calls for environmental technology untested on a commercial scale. Power plant development companies operate nationally, assessing development opportunities in numerous locations throughout the United States (and often internationally) simultaneously. In other states, some companies have successfully taken generation projects from *conception* to *commercial operation* in less than 12 months.

In California, the multi-year siting process, community opposition, risk of litigation, and regulatory price interventions (i.e., retroactive reductions of competitively determined prices) combine to suggest that prudent companies will take their turbine-generator equipment and invest elsewhere. Where companies choose to face the hurdles associated with developing California projects, the nationwide competition for capital and financing often drives investment to other markets or adds a risk premium for California development.

3. Market Structure Matters: The Wholesale Story

There are two fundamental problems with the wholesale market in California: a structure that puts undue pressure on the more volatile short-term markets and the imposition of price caps on purchases of wholesale energy and ancillary services.

The California wholesale market has been designed to incent load participants to move much of their buying and selling activity into the day-ahead, day-of and real-time markets, particularly in the California Power Exchange (CalPX). In any commodity market, it is natural that shorter-term markets will be the most volatile. Contrary to

[10] The average bid from customers in the demand program of the Cal ISO was $38,000 per megawatt month, which translates to approximately $1,200 per megawatt hour assuming the Cal ISO calls the maximum number of curtailment hours set forth in the program.

popular belief, generators and marketers are not inveterate gamblers seeking creative strategies to game markets and drive up prices. [11]

Rather, these companies have invested millions of dollars in California assets and prefer a strategy that permits most, if not all, of their risks to be hedged in forward markets. Thus, many generators sold power ahead of the summer. Data from the CalPX shows that from February to May, forward contracts for June, July and August were available for $55 to $65 a megawatt hour. By August, 2000, forward prices for September were closer to $150, though these prices fell below $100 by the end of August.[12]

California's rules, however, limit the ability of utilities to access the hedging tools normally available to load serving entities. Utilities are permitted to buy only a limited portion of their load in the CalPX's block forwards market, which mitigates some risk, but until recently were not permitted to engage in forward bilateral contracts, options or other risk mitigation tools otherwise in use in the wholesale market. With strict limitations on their use of forward markets and other risk management tools, the utilities have been forced to purchase significant portions of their supply in the spot market.[13]

Additionally, price caps have also created a problem in the Cal ISO's real-time balancing market, driving the load serving entities in California to under-schedule their power needs in the day-ahead markets as a means of achieving a lower overall energy rate. The balancing market price caps provide a free hedging product, allowing utilities to transfer purchases to the real-time market when the price in the day-ahead market exceeds the cap set by the Cal ISO. The Cal ISO has determined that underscheduling has significant operational and reliability impacts; in some hours, the Cal ISO has met as much as 25% of the system needs in the real-time market.[14] During summer 2000, the Cal ISO went out of market to purchase 159,098 megawatt hours, compared to 3,158 megawatt hours in 1999.[15]

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[11] Between 1997 and 1998 a number of competitive power suppliers purchased the gas- and oil-fired generation assets of Pacific Gas & Electric, Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). The three utilities retained over 50% of the generating capacity in the state, and no new California generator owns more than 9% of the generating assets.

[12] CalPX Block Forwards Market Daily Trading Statistics, Power Markets Week. Of course, the closer to delivery day the more forward prices reflect the short-term markets.

[13] In addition, the California Public Utilities Commission (CPUC) rules made forward market hedges subject to reasonableness reviews by state regulators, while spot market purchases were deemed per se reasonable. Accordingly, SCE, for example, hedged about 1,750 megawatts of its 2,200-megawatt limit in June and 3,000- 3,500 of its 5,200-megawatt limit for July- September. SDG&E bought none of its power in the forward market, relying solely on the day ahead and day of markets. See Cal ISO, *Report on California Energy Market Issues and Performance: May-June 2000*, Special Report issued August 10, 2000.

[14] California ISO ADR Committee, *Extension of Price Cap Authority & Level of Price Caps After October 15, 2000.*

[15] California ISO, *Reliability Concerns in Underscheduling of Load,* Memo to Board of Governors, August 25, 2000.

Price caps have also discouraged demand-side responses and load reduction programs. And, with or without price caps, load reduction programs will face a greater challenge in 2001, when the supply and demand balance will be even tighter than it has been in 2000.

4. Market Structure Matters: The Retail Story

Wholesale and retail markets are two sides of the same coin. A healthy wholesale market is a critical component of a well-functioning retail market. If wholesale markets don't work, retail suppliers can't provide customers with products that meet their needs. On the other hand, poorly functioning retail markets disconnect load from price signals and deprive customers of the protection against wholesale price volatility afforded by risk-management products.

While California got a great deal of attention a few years ago for being the first state to open its retail markets, in fact, restructuring in California has been largely at the wholesale level. While customer switching isn't the only measure of success, only about 2% of California's customers (and only about 12.5% of total load)[16] have switched suppliers -- almost exclusively to subsidized green products. When it adopted its restructuring plan, California's decision to freeze rates without establishing a "shopping credit" to facilitate customer choice was fatal to the development of its retail markets. In fact, California's effort to transition to competitive markets was doomed when it froze utility customer rates while tying the back-out rate for direct access customers to wholesale prices in the CalPX. Moreover, utilities were left with overwhelming competitive advantages over new market entrants, including their monopoly on default service.

As a result of this flawed market design, no new retail suppliers were positioned to serve San Diego's load when the rate freeze ended. SDG&E was left as the default supplier with customers having limited access to alternative suppliers and the risk management products they could have provided. Consequently, retail customers were exposed to naturally occurring spot-market price volatility in supply-constrained real-time markets. Under a single default service rate, they are deprived of advance knowledge of their electricity prices and the opportunity to protect themselves from that price risk.

Rather than correcting its flawed market and rate structure, California policy makers have moved to reinstate a retail price freeze. Here again, price caps will have a detrimental effect on the development of the retail market without an adequate shopping credit. Continual retail rate freezes discourage large and small customers from implementing load management programs or securing risk-management products from other energy service providers.

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[16] CPUC, Supplemental Direct Access Implementation Activities Report, August 15, 2000.

5. Solutions

EPSA offers the following suggestions:

- The siting and permitting process for new generation and transmission facilities should be streamlined to meet growing electricity demands.
- Eliminate the CalPX's monopoly. All electricity purchasers (retail or wholesale) should be allowed and encouraged to use all hedging tools available in the market (including bilateral contracts in forward markets), from any supplier.
- Customers and suppliers must be able to see and respond to accurate price signals so as to encourage investment in new generation and allow demand responsiveness.
- Retail markets need to be redesigned to eliminate incumbency advantages and assure market entry, customer choice and service options.
- Creative solutions to environmental limitations need to be encouraged.
- The Federal Energy Regulatory Commission (FERC) needs to critically review and carefully consider the congestion management reform/market redesign proposal being developed by the Cal ISO when it is filed.
- FERC needs to investigate alleged abuse of market power by market participants.
- If policymakers determine that California's market structure requires the continuation of price caps, the limitations on competitive activity and prices should be based on a rigorous market analysis; further, the termination date for the caps should be tied to a well-defined, achievable target (e.g., sufficient capacity or reserve margins).